AR78

TUSK
ENERGY CORPORATION

2005 ANNUAL REPORT

THE DENSITY AND RESISTIVITY CURVES DERIVED FROM THE WELL LOGS OF THE MEGA 12-05 DISCOVERY WELL FORM THE GRAPHIC THEME OF THIS ANNUAL REPORT.

CONTENTS

TUSK

TUSK ENERGY CORPORATION ("TUSK"), IS AN EMERGING JUNIOR EXPLORATION AND PRODUCTION COMPANY ENGAGED IN THE EXPLORATION FOR AND DEVELOPMENT OF OIL AND NATURAL GAS IN WESTERN CANADA. TUSK IS A PUBLIC COMPANY WHICH TRADES ON THE TORONTO STOCK EXCHANGE UNDER THE SYMBOL "TSK".

WWW.TUSK-ENERGY.COM

TUSK maintains an internet site which will include quarterly and annual reports, news releases, and other information of interest to shareholders. All publicly disclosed documents, including our Annual Information Form, may be viewed at www.sedar.com.

STOCKHOLDER INFORMATION

The fiscal year end of TUSK is March 31. As of March 31, 2005 the number of common shares issued and outstanding was 35,030,371. The Annual Meeting of the shareholders of TUSK Energy Corporation will be held at 3:00 p.m. Calgary time on Wednesday, August 10, 2005 in the Wildrose Room at Sheraton Eau Claire Suites, 255 Barclay Parade S.W., Calgary, Alberta.

FORWARD LOOKING STATEMENTS

Certain information regarding TUSK set forth in the document, including management's assessment of TUSK's future plans and operations contain forward looking statements that involve substantial known and unknown risks and uncertainties. These forward looking statements are subject to numerous risks and uncertainties, certain of which are beyond TUSK's control, including the impact of general imprecision of reserve estimates, environmental risks, taxation policies, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal or external sources. TUSK's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward looking statements and, accordingly, no assurance can be given that any of events anticipated by the forward looking statement will transpire or occur, or if any of them do so, what benefits that TUSK will derive therefrom.

MESSAGE TO SHAREHOLDERS

TUSK Energy Corporation is a new oil and gas exploration company formed in November, 2004 upon the re-organization of TUSK Energy Inc. ("Inc"). We are pleased to present our first annual report and to provide shareholders with information on our activities since inception and on our plans for future growth.

The exploration efforts of TUSK are focused in two areas – both in northwestern Alberta. TUSK has made some significant light oil discoveries in the most northerly of these (Mega-Venus) and is developing a number of oil and gas properties in the second focus area (Peace River Arch).

A "MEGA" DISCOVERY?

In Alberta, companies do not get to pick a moniker for their wells – these are dictated by regulatory authorities who have mandated names for the various "strike" areas in the province. We believe that the name assigned to our initial discovery well (Mega) may be an apt one in the case of TUSK's main focus area in northern Alberta and the name assigned to some of the wells drilled in 2005 (Venus) may also fit the bill.

TUSK is a little company looking for "big" oil in northern Alberta. Our quest began with the drilling of TUSK Mega 12-5-101-7 W6M, a 2,600 metre wildcat well, in the first quarter of 2004. The well was drilled on a large feature defined by 3-D seismic. It encountered a thick column of very light (52° API) oil pay and led to the initiation of an aggressive and on-going journey of discovery which, in the opinion of TUSK management, is working out very well.

OPERATIONAL CHALLENGES

The entire Mega-Venus area is only accessible during the winter months after the ground is sufficiently frozen to allow for the movement of heavy equipment over the muskeg. Drilling operations, the shooting of seismic surveys and the construction of pipelines are all confined to a short winter period – generally about 3 months from mid-December to mid-March. Effective operations during the short access season require substantial planning and organization during the summer months. All operational plans must be submitted to the Alberta Environment department by mid-October each year.

MEGA 12-05 DISCOVERY WELL

The 12-05 well was production tested for 57 hours in mid-March, 2004 at the end of the winter operating season. The well flowed, restricted by a ½" choke, an average of 537 boepd (437 bopd + 603 Mcfd) with no water during this short test period. TUSK has a 47% BPO (28.2% APO) interest in the well.

A SUMMER OF ACTIVITY

During the summer and fall of 2004, TUSK took concrete actions to exploit its competitive advantage while the results of the 12-05 were held confidential. More than 650 kilometres of 2-D and 30 km² of 3-D seismic were acquired and we acted decisively to substantially increase our land holdings. TUSK made farm-in arrangements and Crown purchases which increased its overall land holdings in the area and on similar prospects elsewhere in northern Alberta to more than 143,000 gross (>67,000 net) acres – or more than 200 square miles. Average cost of Crown acquisitions was about $150 per hectare ($60 per acre).

New well locations and the route for a 6" pipeline to carry produced hydrocarbons out of the area were surveyed during the summer months and TUSK made plans for the shooting of two 3-D seismic surveys and contracted three drilling rigs for the 2004-2005 winter season.

MEGA ACTIVITY – 2004-05 WINTER SEASON

- production testing of the 12-05 well confirmed initial optimism;
- drilled and cased six Keg River tests;
- shot 77 km² of new 3-D seismic;
- completed 6" pipeline;
- made strategic property acquisition;
- drilled, cased and tied-in new Debolt gas well;
- tied-in three Keg River wells to new pipeline.

12-05 PRODUCTION TESTING

Production testing of the 12-05 well resumed on December 18, 2004 with oil flow, restricted for evaluation purposes by a ¾" choke. Production averaged 180 bopd with no water and minor gas against a flowing tubing pressure of almost 1,000 psi during a 30 day testing period. A steady flow rate was maintained during the entire flow period and no attempt was made to open the valve to quantify the maximum flowing capability of the well. The 12-05 well was shut-in on January 18 to evaluate pressures. Recovered oil was all extremely light with gravity measured between 52° and 56° API. The well was returned to production on February 10 after recovery of bottom-hole pressure recording devices. Analysis of the pressure data indicated no depletion.

Subsequently, the 12-05 well was produced at 315 bopd with no water and minor gas for a second flowing period until some drilling mud was unloaded by the formation causing flowing pressure to rise and the production rate to increase to 450 bopd with no change in choke size.

DRILLED SIX KEG RIVER TESTS

Five Keg River tests were drilled and cased to total depth. Intermediate casing had to be run to a depth of 1,936 metres in the sixth well prior to the move-out of the rig in mid-March due to warm weather. Three of the wells were drilled within three miles of the 12-05 well while one was drilled approximately 15 miles northwest and another approximately 15 miles southwest. Of the five wells which reached total depth, three were tested sufficiently to confirm hydrocarbons and two require additional testing. Detailed information about these wells will not be disclosed until required by regulation.

SHOT 3-D

Field data acquisition for two large 3-D seismic surveys (TUSK 50%) began in mid-February. These programs covered areas of 38 and 39 km² respectively. Shooting was completed in early March.

PIPELINE CONSTRUCTION

Despite the vicissitudes of weather, TUSK successfully completed the construction of two new pipelines in the general area. The decision to proceed with construction of about 23 km and the purchase of 10 km of 6″ pipeline to move hydrocarbons out of the Mega area was made after evaluating the producing characteristics of the 12-05 well for seven weeks and after having drilled and logged several of the additional Keg River tests. Construction began in mid-February and the 6″ line was completed and pressure tested in late March. Three of the Keg River wells, the initial discovery and two of those drilled in the early 2005, were tied-in to the pipeline at or near to the end of the fiscal year. A second pipeline, a 2.5 km 4″ line connecting a Debolt gas well purchased by TUSK in late January to an existing pipeline, was also completed by the end of March.

PROPERTY ACQUISITION

TUSK acquired a working interest of slightly more than 40% in 12 sections (12 miles) of oil and gas rights in the general Mega-Venus area in January. The land block was located approximately 15 miles to the southwest of the 12-05 discovery well and were contiguous with a block of existing TUSK acreage containing a Debolt gas discovery drilled and put on production in the winter of 2003-2004. The purchase included a drilled and cased Debolt gas well which was subsequently tied-in by TUSK in March. An additional Debolt gas well and a Keg River test were drilled and cased by TUSK prior to the end of the winter season.

FUTURE PLANS – MEGA AREA

TUSK plans a more active program in the coming winter. During the summer of 2005 we will survey additional drilling locations and the route for approximately 25 km of additional 6″ pipeline. Plans for the winter of 2005-2006 include the drilling of 10 to 15 Keg River tests, construction of the new pipeline, up to 90 km² of new 3-D seismic and the construction of expanded fluid handling capability at the southern terminus of the Mega pipeline. The drilling locations are based upon the detailed geological analysis of our technical staff and most are defined by 3-D seismic. At the present time, three drilling rigs have been committed to the winter program. The number of wells which may be drilled will depend upon the number of rigs we are able to contract for work in the area. Each rig should be able to drill a minimum of three Keg River tests during the winter season.

PEACE RIVER ARCH

In addition to its exploration and development efforts in the general Mega-Venus area, TUSK is exploring the Triassic Montney play in the Peace River Arch area. The numerous opportunities we have identified arise from the knowledge base of our operational and geotechnical teams – knowledge derived through our discovery and development of the Gage/George Montney light oil field.

TUSK drilled 7 wells at Gage during its first fiscal year. All were successful resulting in 6 oil wells (3 net) and one gas well (0.50 net). Construction of a central battery facility and in-field pipelining to tie wells into the new facility started in February and was completed subsequent to the end of the fiscal year. When fully operational, the new facility should lead to decreased operating costs as it will allow for the release of rental equipment used on single well batteries and the minimization of trucking costs. Application has been made for a holding covering much of the Gage field area which will allow for infill drilling in the coming months. TUSK expects to drill at least five infill wells on the Gage property in the late summer and fall of calendar 2005.

TUSK is involved in an active exploration program for Montney prospects in an approximate 800 square mile area of the northern Peace River Arch. Five prospects have been defined. During the 2005 fiscal year ended March 31 TUSK drilled a dry hole (0.325 net) on one of these prospects and we were drilling on a second prospect (now a new pool oil

discovery – 30% working interest) as of the end of the fiscal year. Since then, two more prospects have been drilled resulting in a new pool oil discovery (50%) and a new pool gas discovery (50%). Production from all three of these properties is expected to begin in our second quarter (July-September).

TUSK will continue to generate new opportunities for growth on the Montney play and elsewhere in the general Peace River Arch area. Our activity in this area will primarily occur during the spring, summer and fall – balancing our winter activity in northern Alberta.

DRILLING

TUSK has been an active driller since its formation in early November, 2004. A total of 20 wells were drilled and rig released prior to the end of the fiscal year resulting in 8 gross (3.75 net) oil wells, 8 gross (3.60 net) gas wells, 3 gross (0.36 net) dry holes and one gross (0.28 net) suspended well at Mega which will be re-entered and drilled to total depth in the first part of the winter 2005-2006 drilling season. Based on the 19 wells which reached their objective, our net success rate was in excess of 95%. TUSK operates in all of its focus areas.

AREA	LOCATION	OPERATOR	W.I. %	STATUS	
				RIG RELEASE	JUNE 28, 2005
Mega	04-02-101-07 W6M	TUSK	47	Tight hole	Producing
	06-36-101-09 W6M	TUSK	50	Tight hole	Tight hole
	10-01-101-07 W6M	TUSK	47 BPO [1]	Tight hole	Tight hole
	03-06-101-06 W6M	TUSK	28.2	Tight hole	Producing
	03-11-100-08 W6M	TUSK	50	Tight hole	Tight hole
	08-06-101-06 W6M	TUSK	28.2	Suspended	Tight
Snowfall	06-36-99-08 W6M	TUSK	43.25	Gas	SIGW
Gage	14-24-82-04 W6M	TUSK	50	Oil	Producing
	08-07-82-03 W6M	TUSK	50	Oil	Producing
	12-08-82-03 W6M	TUSK	50	Oil	Producing
	02-19-82-03 W6M	TUSK	50	Oil	Producing
	15-18-82-03 W6M	TUSK	50	Gas	SIGW
	15-07-82-03 W6M	TUSK	50	Oil	Producing
	03-19-82-07 W6M	TUSK	50	Oil	Producing
Gage North	08-12-83-04 W6M	TUSK	32.5	D&A	D&A
Whitecourt	02-29-60-12 W5M	Third Party	3.68	Cased	D&A
	05-15-60-12 W5M	Third Party	ORRI	D&A	D&A
	01-24-60-12 W5M	Third Party	20	Gas	SIGW
	01-26-60-13 W5M	TUSK	50	Gas	SIGW
Chinchaga	16-28-97-07 W6M	TUSK	55.56	Gas	SIGW

(1) 28.2% BPO

LAND

TUSK is a relatively new company with a substantial undeveloped land base of approximately 219,000 gross acres (119,000 net acres). More than 65% of these lands are located in the general Mega-Venus exploration area in northern Alberta.

PRODUCTION

Production during the year ended March 31, 2005 averaged 282 boepd (161 bpd of oil and 728 Mcfd of natural gas) reflecting the early stage of development of TUSK's properties.

Production from the Mega-Venus area began in early May when surface facilities were completed at the southern terminus of the Mega pipeline. Initial production is limited by regulation. Applications to increase the MRL (Maximum Rate Limitation) have been made and increases in producing rates above the base allowable per well can be expected in the future as more is learned about the producing characteristics of the wells, applications for modification of the MRL per well are approved and as the liquids handling capabilities at the southern terminus of the Mega pipeline are expanded.

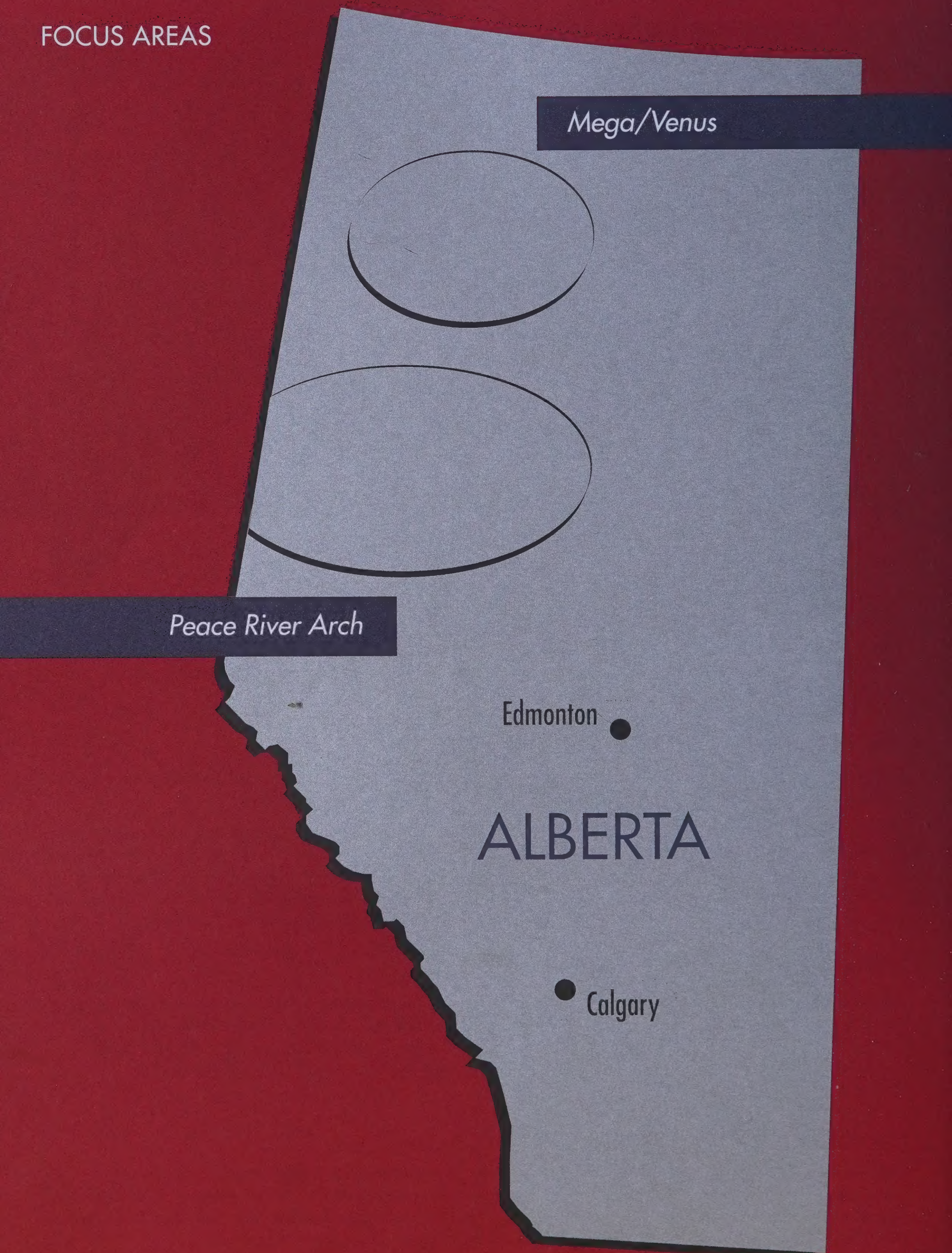
FINANCIAL

TUSK has a strong balance sheet with the available cash to carry out its exploration and development programs and no bank debt. TUSK completed three private placements during the fiscal year involving the sale of 17,370,000 common shares at an average price of $2.95 per common shares for total gross proceeds of $51,280,500. The most recent financing, the "bought deal" private placement of 7,000,000 common shares at $4.50 for gross proceeds of $31.5 million, closed on March 14.

INVESTMENT

TUSK owns 17.1% of the common shares of Loon Energy Inc., a company with a focus on international oil and gas exploration and development which is listed on the TSX Venture Exchange (Symbol – LEY). Market value of the common shares owned by TUSK as of June 28 was $12.6 million. The total cost of the investment in Loon shares was $4.15 million. The main focus of Loon is on Colombia, where an active drilling program is planned starting in July.

FOCUS AREAS



CORPORATE GOVERNANCE

Guidance is provided by a qualified and able group of directors. Two directors retired in 2005 after serving our predecessor company, TUSK Energy Inc. for many years and after having assisted with the start-up of TUSK Energy Corporation. William E. Code retired March 29 after serving the TUSK companies since June 1992. John D. Morgan will retire at the August meeting of shareholders after serving the TUSK companies since June 1995. Bill and John both made a significant contribution to the TUSK companies and we thank them for their efforts on behalf of the shareholders.

Earl T. Hickok, P. Eng. joined the board effective March 29. Earl was a co-founder of both Advantage Energy Services Ltd., an engineering consulting firm specializing in maximizing the value of oil and gas assets, and Tecskor Corporation. He is currently President & Chief Executive Officer of Tecskor, a private software company which provides organizational and business management software for oil and gas and government applications.

Murray D. Smith will be proposed as a new director at the shareholders meeting in August. Murray was a Member of the Legislative Assembly of the Province of Alberta since 1993. He served as a Minister in the Cabinet of the Government of Alberta since 1994 until his retirement from politics in November, 2004. He was appointed to four different cabinet portfolios (Economic Development, Labour, Gaming, Energy) and last served as Minister of Energy since 2001. Murray currently represents the Government of Alberta as Minister-Counsellor and is based at the Embassy of Canada, Washington, D.C.

OUTLOOK

The senior management of TUSK has confidence in our growth potential and all have a significant personal investment in the common shares. We welcome all fellow shareholders who have joined us on this journey of discovery.

TUSK will face stiff competition for drilling rigs and other oilfield services from much larger competitors and is subject to the substantial risks inherent in exploration for deep targets in new areas. Our Mega area is accessible for major work only during the winter months and either a deep freeze or a warming trend can negatively impact both the pace and cost of exploration and development activities.

So far, we have been successful at overcoming the challenges and difficulties we have encountered. The results of our drilling programs have, in the estimation of management, been outstanding. TUSK has an extensive land base and a substantial amount of 2-D and 3-D seismic information in our key exploratory area. The abilities of our geotechnical and operational teams are evidenced by our results.

The Company has overcome substantial risks and challenges to, we believe, uncover an important new play that may have broad areal extent and repeatability. Welcome to the adventure and good luck to all shareholders.

On behalf of the board of directors

"signed"	"signed"
Ian T. Brown President	Norman W. Holton Chairman

WE HAVE OVERCOME SUBSTANTIAL RISK AND CHALLENGES TO UNCOVER AN IMPORTANT NEW PLAY THAT MAY HAVE BROAD AREAL EXTENT AND REPEATABILITY.

MANAGEMENT'S FINANCIAL DISCUSSION & ANALYSIS

For the fiscal year ended March 31, 2005

The following analysis and discussion is provided by the management of TUSK Energy Corporation ("TUSK" or the "Company") is dated June 16, 2005 and should be read in conjunction with the audited consolidated financial statements for the period from November 2, 2004 to March 31, 2005.

Basis of Presentation – The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles. The reporting and the measurement currency is the Canadian dollar.

Non-GAAP Measurements – The Management's Discussion and Analysis contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles as an indicator of the Company's performance. The Company's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow per share from operations is a measure that is widely used in the oil and gas industry and is used by the Company to determine cash available to fund future growth through capital investment and to repay debt. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows in the unaudited interim consolidated financial statements and the audited consolidated financial statements. The Company also presents cash flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

Barrels of Oil Equivalent – BOE may be misleading, particularly if used in isolation. The BOE conversion ratio for natural gas used in this report is derived by converting natural gas to BOE in the ratio of six Mcf to one barrel of oil equivalent. This ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The conversion ratio is an industry accepted norm and is not based on either energy content or current prices.

REORGANIZATION

On October 28, 2004 the shareholders of TUSK Energy Inc. approved a Plan of Arrangement reorganizing that company into TKE Energy Trust and TUSK Energy Corporation ("TUSK"). The Plan of Arrangement received court approval and became effective on November 2, 2004.

SUMMARY INFORMATION

Period from November 2 to March 31, 2005		
Product Volumes		
Oil, bpd		153
NGL, bpd		8
Natural Gas, Mcfd		728
BOEPD		282
Summary of Product Prices		
Oil, per Barrel	$	61.48
NGL, per Barrel	$	29.46
Natural Gas, per Mcf	$	6.41
Financial		
Funds from Operations	$	449,446
Net Loss	$	(1,912,718)
Funds from Operations per Share	$	0.02
Net Loss per Share	$	(0.07)
Cash Capital Expenditures	$	21,640,334

SUMMARY INFORMATION PER BOE

TUSK is a relatively new company in the early stage of its development. Operating and transportation expense is high, on a per boe basis, due to the expense of single well batteries and trucking of fluids (see "Operating Expenses" and "Transportation Expenses").

Period from November 2 to March 31, 2005	($)
Gross Revenue	50.63
Royalties, Net of ARTC	10.33
Net Revenue	40.30
Operating Expense	17.96
Transportation Expense	7.18
Net Operating Revenue	15.16
General & Administration	4.60
Current Income Taxes	–
Cash Flow per BOE	10.56

OIL AND GAS REVENUES

Oil and gas revenue, before royalties, for the reporting period ended March 31, 2005 was $2,155,362. Boe production for the period was 42,575 boe.

Period from November 2 to March 31, 2005		
Oil and Gas Revenues, before Royalties	$	2,155,362
Oil Production (bbls)		23,009
Oil Price ($/bbl)	$	61.48
NGL Production (bbls)		1,255
NGL Price ($/bbl)	$	29.46
Gas Production (Mcf)		109,866
Gas Price ($/Mcf)	$	6.41
BOE Production		42,575
BOE per Day		282

ROYALTIES

Total royalties, net of ARTC, were $439,850 ($10.33 per BOE) for the period ended March 31, 2005. Net royalties represented 20.4% of gross revenues in 2005.

Period from November 2 to March 31, 2005	($)
Crown Royalties	231,784
Freehold Royalties	66,122
Gross Overriding Royalties	148,431
	446,337
Alberta Royalty Tax Credit	6,487
Net Royalties	439,850
Net Royalties per BOE (6:1)	10.33

OPERATING EXPENSES

TUSK is a new company in the early stages of its development with essentially all production coming from new pools. In the early stages of production from new pool discoveries, operating costs can be high because of the inherent inefficiencies of single well batteries, trucking and third party handling charges. The use of single well batteries allows for early production and a more complete assessment of the long term productivity of new wells prior to the expenditure of additional capital for pipelines and facilities. TUSK has completed this assessment at Gage and completed a central battery and water disposal facilities for that property in June, 2005. In the Mega-Venus area, TUSK commissioned a new regional pipeline and local well tie-in of three wells in April, 2005. These company-owned facilities should substantially reduce TUSK's operating expenses in the next fiscal year. Operating expenses for the period ended March 31, 2005 were $764,455 ($17.96 per BOE).

TRANSPORTATION EXPENSES

The early stage of development of the producing properties of the Company also impacts initial transportation costs as all liquid produced during the period ended March 31, 2005 had to be trucked to market. The newly constructed facilities at Mega and Gage will substantially reduce transportation expenses which were $7.18 per boe for the period.

DEPLETION, DEPRECIATION AND ACCRETION (DD&A)

TUSK is in the early stages of exploration and development at its Mega property which has led to a high DD&A on a BOE basis. Depletion, depreciation and accretion was $1,147,124 for the period ended March 31, 2005, which represents a provision of $26.94 per BOE of production.

GENERAL AND ADMINISTRATIVE

Gross general and administrative costs for the period ended March 31 was $901,282 in 2005, including $768,807 charged under the Technical Services Agreement with TKE Energy Trust.

Period from November 2 to March 31, 2005

	($)
Gross General and Administrative	901,282
Overhead Recoveries	(546,422)
Exploration & Development Costs Capitalized	(159,000)
Net General and Administrative	195,860
Per BOE	4.60

PROVISION FOR INCOME TAXES

The provision for income taxes for the period ended March 31, 2005 was comprised of a tax reduction of $70,000. Additionally, as at March 31, 2005, the Company has tax deductions of approximately $36.8 million that are available to shelter future taxable income.

EQUITY

During the fiscal year ended March 31, 2005, the Company did three common share financings that raised a total of $51,280,500. On November 2, 2004, the Company closed a private placement that issued 3,000,000 common shares at a price of $1.00 per share. On December 1, 2004 the Company closed a private placement that issued 5,500,000 common shares at a price of $2.15 per common share and 1,870,000 flow-through common shares at a price of $2.65 per flow-through common share. On March 14, 2005, the Company closed a private placement that issued 7,000,000 common shares at a price of $4.50 per common share. As of March 31, 2005 and at June 16, 2005 there were 35,030,371 common shares issued and outstanding.

INVESTMENT

The Company has invested a total of $4,150,643 in approximately 11.5 million common shares of Loon Energy Inc. ("Loon"). Loon is an oil and gas company listed on the TSX Venture Exchange (Symbol – LEY). The Company acquired approximately 7.9 million common shares, representing 17.3% of the total number of Loon common shares then outstanding, for $794,339 ($0.10 per common share) as part of the Plan of Arrangement. TUSK acquired a further 3.6 million common shares at a cost of approximately 3.4 million ($0.95 per common share) by purchasing 16.5% of the available common shares in a private placement of Loon common shares which closed on March 31, 2005 and through minor market purchases during the period ended March 31, 2005. As of March 31, 2005 TUSK owned 17.1% of the total number of issued and outstanding Loon common shares. The market value of the Loon common shares owned by TUSK was $11.4 million as of March 31, 2005. TUSK is represented on the board of directors of Loon by two officers of TUSK (Norman Holton and Edwin Beaman). Mr. Holton is Chairman of the board of directors of Loon and, as of March 31, was the Chief Executive Officer of Loon.

Loon is a Canadian public company with international oil and gas exploration and development operations in Latin America and south-central Europe. Main focus areas are Colombia and Slovenia. Further information on Loon may be obtained at www.loon-energy.com or by searching for corporate filings made by Loon on www.sedar.com.

CAPITAL EXPENDITURES

Cash capital additions, excluding acquisitions and divestitures, for the period ended March 31, 2005 were $21,640,334.

Period from November 2 to March 31, 2005

	($)
Land	1,981,503
Seismic & Exploration	1,432,557
Drilling & Completion	14,993,340
Facilities	3,232,934
Total	21,640,334

LIQUIDITY AND CAPITAL RESOURCES

TUSK had working capital of $20,484,065 at March 31, 2005.

The Company has a financing arrangement with a Canadian financial institution whereby the Company was provided a $3 million revolving production loan of which none was drawn as at March 31, 2005.

On an ongoing basis TUSK will typically utilize three sources of funding to finance its capital expenditure program: internally generated cash flow from operations; debt where deemed appropriate; and new equity issues, if available on favourable terms. When financing corporate acquisitions, TUSK may also assume certain future liabilities. Commodity prices and production volumes have the largest impact on TUSK's ability to generate adequate cash flow to meet all its obligations. A prolonged decrease in commodity prices would negatively affect TUSK's cash flow from operations and would also likely result in a reduction in the amount of bank loan available. If TUSK's capital expenditure program does not result in sufficient additional reserves and/or production it would likely have a negative impact on TUSK's liquidity.

TUSK may adjust its capital expenditure program depending on the commodity price outlook. TUSK believes that working capital, internally generated cash flow and incremental bank debt should be sufficient to finance current operations and planned capital spending in the next year.

BUSINESS RISKS

The marketability and price of products owned or that may be acquired or discovered by TUSK will be affected by numerous factors beyond the Company's control. TUSK must compete in all aspects of its operations with a number of other corporations that have equal or greater technical or financial resources. The ability of the Company to market its natural gas may depend on its ability to acquire space in pipelines that deliver natural gas to commercial markets. The Company is subject to variable weather conditions which may affect the ability to drill, complete and/or produce wells and protracted negotiations with surface land owners may delay access to drilling locations and locations for facilities.

The Company is also subject to market fluctuations in the prices of products, exchange rates, uncertainties related to the proximity of its reserves to pipelines and processing facilities and extensive government regulation.

PLAN OF ARRANGEMENT

On November 2, 2004 the TUSK Energy Inc. closed a Plan of Arrangement (the "Arrangement") which was approved at a special meeting of shareholders held October 28, 2004. The TUSK Energy Inc. shareholders voted 99.9% in favour of the resolution approving the Arrangement. Pursuant to the Arrangement, each common share of TUSK Energy Inc. was exchanged for 0.5 units of TKE Energy Trust (the "Trust") or shares exchangeable into units of the Trust and 0.5 common shares of TUSK Energy Corporation ("TUSK"). Both the Trust and TUSK commenced trading on the Toronto Stock Exchange on November 5, 2004. Also, as part of the Arrangement, new banking facilities were put in place. The TUSK facility is a revolving loan in the amount of $3,000,000 which bears interest at the bank's prime lending rate plus 0.75%. The bank facility is scheduled to be reviewed July, 2005.

RELATIONSHIP WITH TKE ENERGY TRUST

TECHNICAL SERVICES AGREEMENT

In conjunction with the Plan of Arrangement, TUSK and TKE Energy Trust entered into a Technical Services Agreement which provides for the shared services required to manage TUSK's activities and govern the allocation of general and administrative expenses between the entities. Under the Technical Services Agreement, TUSK is charged a technical services fee by TKE Energy Trust, on a cost recovery basis, in respect of management, development, exploitation, operations and marketing activities on the basis of relative production and capital expenditures. For the period the technical service fee was $768,807.

QUARTERLY DATA

The following tables set forth selected quarterly financial information for the last eight financial quarters.

	Three Months Ended March 31, 2005	Period Ended Dec. 31, 2004
Production per Day		
Oil and NGLs (bbls)	195	114
Natural Gas (Mcf)	834	589
Boe	334	212
Netback per Boe ($)	15.23	14.98
Petroleum and Natural Gas Sales, net ($)	1,287,137	428,375
Funds from Operations ($)	379,609	69,837
Per Common Share (basic) ($)	0.01	–
Per Common Share (diluted) ($)	0.01	–
Net Income (loss)	(1,124,038)	(788,680)
Per Common Share (basic) ($)	(0.04)	(0.03)
Per Common Share (diluted) ($)	(0.04)	(0.03)

FOURTH QUARTER ANALYSIS

	Three Months Ended March 31, 2005	Period Ended Dec. 31, 2004
Daily Production		
Oil (bpd)	187	105
NGLs (bpd)	8	9
Natural Gas (Mcfd)	834	589
BOEPD	334	212
Summary of Product Prices		
Oil per bbl	$ 66.98	$ 46.56
NGLs per bbl	$ 27.51	$ 32.03
Gas per MCF	$ 6.55	$ 6.10
Financial '000's Except per Share Data		
Oil and Gas Revenues	1,637	518
Royalties, Net or ARTC	350	90
Oil and Gas Operating & Transportation	829	241
General and Administrative	84	112
Depletion, Depreciation and Accretion	867	280
Stock-Based Compensation	621	664
Cash Flow from Operations	379	70
Net Income (Loss)	(1,124)	(789)
Per Unit Basic	(0.04)	(0.03)
Per Unit Diluted	(0.04)	(0.03)
Capital Expenditures	15,873	5,767
Working Capital	20,484	10,913

OIL AND GAS REVENUES

Oil and gas revenues were $1,637 thousand in the three months ended March 31, 2005 compared to $518 thousand in the period ended December 31, 2004. The 216% increase in the three months ended March 31, 2005 compared to the period ended December 31, 2004 was mainly due to a 58% increase in production from 212 boepd in 2004 to 334 boepd in 2005 and a dramatic increase in the average price in oil from $46.56 per barrel to $66.98 per barrel, a 44% increase.

CRITICAL ACCOUNTING ESTIMATES

DEPLETION AND DEPRECIATION EXPENSE

The Company uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs if amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proven reserves or future development costs have a direct impact on depletion and depreciation expense. Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depletion and depreciation expense.

FULL COST ACCOUNTING CEILING TEST

Oil and gas assets are evaluated at least annually to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the oil and gas assets. If the carrying value of the oil and gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of costs and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk-free rate. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

ASSET RETIREMENT OBLIGATIONS

The Company records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost. The total future asset retirement obligation is an estimate based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligation is an estimate that is subject to measurement uncertainty and any change would impact the liability.

INCOME TAXES

The determination of the Company's income and other tax liabilities required interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

ADDITIONAL INFORMATION

Additional information regarding the Company and its business and operations, including the annual information form ("AIF"), the 2005 annual report, news releases and all statutory filings are available at www.sedar.com. Copies of these documents can also be obtained by contacting TUSK by mail at Suite 1900, 700 – 4th Avenue S.W., Calgary, Alberta, T2P 3J4 or by e-mail at mwiltshire@tusk-energy.com. This information is also accessible on the company's website at www.tusk-energy.com.

AUDITED FINANCIAL STATEMENTS

FISCAL YEAR ENDED MARCH 31, 2005

MANAGEMENT REPORT

The management of TUSK Energy Corporation is responsible for the financial information and operating data presented in this annual report.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgements. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this annual report has been prepared on a basis consistent with that in the financial statements.

TUSK Energy Corporation maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded.

The Audit Committee of the Board of Directors, composed of non-management directors, meets regularly with both management and external auditors, to discuss auditing (external and joint venture), internal controls, accounting policy, financial reporting matters and reserves determination process. The Committee reviews the annual financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

The financial statements have been audited by KPMG, LLP, the independent auditors, in accordance with Canadian generally accepted auditing standards on behalf of the shareholders. KPMG, LLP have full and free access to the Audit Committee.

"signed"	"signed"
Ian T. Brown President and Chief Executive Officer	Gordon K. Case Vice President and Chief Financial Officer

June 16, 2005

AUDITORS' REPORT

To the Shareholders of TUSK Energy Corporation

We have audited the balance sheet of TUSK Energy Corporation as at March 31, 2005 and the statements of operations and deficit and cash flows for the period from November 2, 2004 to March 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company at March 31, 2005 and the results of its operations and its cash flows for the period from November 2, 2004 to March 31, 2005 in accordance with Canadian generally accepted accounting principles.

"signed"

KPMG,LLP
Chartered Accountants
Calgary, Canada

June 16, 2005

BALANCE SHEET

	March 31, 2005
ASSETS	($)
Current Assets	
Cash and Cash Equivalents	8,304,582
Short-Term Investment (Note 4)	19,999,810
Accounts Receivable	15,545,817
Prepaid Expenses	217,964
	44,068,173
Investment (Note 5)	4,150,643
Property, Plant and Equipment (Note 6)	34,335,331
Future Tax Asset (Note 9)	1,335,000
	83,889,147
LIABILITIES AND SHAREHOLDERS' EQUITY	
Current Liabilities	
Accounts Payable	23,584,108
	23,584,108
Asset Retirement Obligation (Note 3)	389,168
Shareholders' Equity	
Share Capital (Note 8)	60,543,549
Contributed Surplus (Note 8)	1,285,040
Deficit	(1,912,718)
	59,915,871
	83,889,147

See Accompanying Notes

STATEMENT OF OPERATIONS AND DEFICIT

	Period from November 2 to March 31, 2005
	($)
Revenue	
Oil and Gas Revenues	2,155,362
Royalties, Net of Alberta Royalty Tax Credit	439,850
	1,715,512
Expenses	
Oil and Gas Operating	764,455
Transportation	305,751
General and Administrative	195,860
Stock-Based Compensation	1,285,040
Depreciation, Depletion and Accretion	1,147,124
	3,698,230
Loss Before Taxes	(1,982,718)
Income Taxes	
Future Tax Reduction (Note 9)	(70,000)
Loss for the Period and Deficit, End of Period	(1,912,718)
Net Loss per Share (Basic and Diluted)	(0.07)

See Accompanying Notes

STATEMENT OF CASH FLOW

	Period From November 2 to March 31, 2005
	($)
Operating Activities	
Net Loss	(1,912,718)
Items not Requiring Cash:	
Stock Based Compensation	1,285,040
Depreciation, Depletion and Accretion	1,147,124
Future Tax Reduction	(70,000)
Funds from Operations	449,446
Change in Non-cash Working Capital	(2,304,668)
Cash Provided by Operating Activities	(1,855,222)
Financing Activities	
Issue of Capital Stock	51,280,500
Share Issue Costs	(2,724,846)
Bank Indebtedness	(2,000,000)
	46,555,654
Investing Activities	
Short-Term Investments	(19,999,810)
Investment	(3,356,304)
Property, Plant and Equipment	(21,640,334)
Change in Non-cash Working Capital	8,600,598
	(36,395,850)
Increase in Cash and Cash Equivalents during the Period and Cash and Cash Equivalents: End of Period	8,304,582
Interest Paid	4,986

See Accompanying Notes

NOTES TO FINANCIAL STATEMENTS

Period November 2, 2004 to March 31, 2005

1. ACCOUNTING POLICIES

Nature of Business and Basis of Presentation

TUSK Energy Corporation ("TUSK" or the "Company") was incorporated on September 24, 2004 and commenced commercial operations on November 2, 2004 under a Plan of Arrangement entered into by TUSK Energy Inc., TKE Energy Trust, and TUSK ("Plan of Arrangement"). Under the Plan of Arrangement various assets of TUSK Energy Inc. were transferred to TUSK. As a result, the financial statements presented are for the period from November 2, 2004 to March 31, 2005.

TUSK is involved in the exploration, development and production of petroleum and natural gas in British Columbia, Alberta and Saskatchewan. The financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

The preparation of financial statements in conformity with generally accepted accounting principles required management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

Joint Operations

Substantially all of the exploration, development and production activities are conducted jointly with others and accordingly, the Company only reflects its proportionate interest in such activities.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the provision for asset retirement obligations are based on estimates. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

Cash and Short-Term Investments

Cash and short-term investments consist of cash in the bank, less outstanding cheques and short-term deposits with a maturity of less than three months.

Petroleum and Natural Gas Properties

The Company follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

Petroleum and natural gas assets are evaluated at least annually to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the petroleum and natural gas assets. If the carrying value of the petroleum and natural gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs are discounted using the risk-free rate. Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20% or more, in which case a gain or loss would be recorded.

Depletion and Depreciation

Capitalized costs, together with estimated future capital costs associated with proven reserves, are depleted and depreciated using the unit-of-production method based on estimated gross proven reserves of petroleum and

natural gas as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Costs of significant unproved properties, net of impairments, are excluded from the depletion and depreciation calculation.

Asset Retirement Obligations

The Company records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

Income Taxes

The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Stock Based Compensation Plan

The Company applies the fair value method for valuing stock option grants. Under this method, compensation cost, attributable to share options granted to employees, contractors, officers and directors of TUSK is measured at fair value at the grant date and expensed with a corresponding increase to contributed surplus. Upon the exercise of the stock options, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

The Company has not incorporated an estimated forfeiture rate for stock options, rather, the company accounts for actual forfeiture as they occur.

Per Share Information

Per share information is calculated on the basis of the weighted average number of Common Shares outstanding during the fiscal year. Diluted per share information reflects the potential dilution that could occur if securities or other contracts to issue Common Shares were exercised or converted to Common Shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options plus the unamortized stock compensation cost would be used to buy back Common Shares at the average market price for the period.

Flow-Through Shares

Flow-through shares are issued at a fixed price and the proceeds are used to fund qualifying exploration and development expenditures within a defined period. The qualifying deductions funded by the flow-through arrangements are renounced to investors in accordance with Canadian tax legislation. To recognize the foregone tax benefits of flow-through shares, share capital is reduced and a future income tax liability is recorded for the estimated future tax cost of the renounced expenditures, when the expenditures are renounced.

2. TRANSFER OF ASSETS AND COMMENCEMENT OF COMMERCIAL OPERATIONS

Under the Plan of Arrangement, TUSK Energy Inc. transferred to TUSK approximately 5% of TUSK Energy Inc.'s producing and exploratory petroleum and natural gas properties and a proportion of its bank debt and other liabilities. The transfer of assets and liabilities has been accounted for as a continuity of interest because at the time of this transaction, TUSK Energy Inc. and TUSK were related companies. This resulted in the transfer of assets and related liabilities to TUSK to be at their carrying value as follows:

($ Thousands)	Amount
Net assets received:	
Investment	794,339
Petroleum and natural gas properties	13,452,953
Future income tax asset	2,060,000
Accounts payable assumed	(1,524,397)
Bank debt assumed	(2,000,000)
Deficit	4,877,476
Common shares issued (17,660,371 shares) (Note 7)	17,660,371
Reduction of stated capital	(4,877,476)
Common shares	12,782,895

Pursuant to the Plan of Arrangement, the deficit was eliminated by an equal reduction to stated share capital of common shares.

Relationship with TKE Energy Trust

In conjunction with the Plan of Arrangement, TUSK and TKE Energy Trust ("TKE") entered into Technical Services Agreement which provides for the shared services required to manage TUSK's activities and govern the allocation of general and administrative expenses between the entities. Under the Technical Services Agreement, TUSK is charged a technical services fee by TKE, on a cost recovery basis, in respect of management, development, exploitation, operations and marketing activities on the basis of relative production and capital expenditures. For the period ended March 31, 2005 (the "period") the technical services fee was $768,807. The Technical Services Agreement has no set termination date and will continue until terminated by either party with six months prior written notice to the other party or at some other date as may be mutually agreed.

As a result of the Plan of Arrangement, TUSK and TKE have joint interest in certain properties and undeveloped land. These joint interest properties are governed by standard industry agreements.

As at March 31, 2005, accounts receivable and accounts payable included a net $6.5 million due from TKE, which includes standard joint venture amounts, including revenue. During the period, TUSK reimbursed TKE approximately $1.3 million for capital expenditures, incurred between the announcement of the Plan of Arrangement and the formation of TUSK, that are related to lands subsequently owned by TUSK.

3. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately $781,000 which will be incurred between 2009 and 2017. The majority of the costs will be incurred between 2009 and 2017. A credit-adjusted risk-free rate of 8.94% percent and an inflation rate of 2.0 percent were used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligations is provided below:

Asset retirement obligations	Period ended March 31, 2005
Liabilities incurred in period	381,914
Accretion expense	7,254
Balance, end of period	389,168

4. SHORT-TERM INVESTMENT

The short-term investment is a banker acceptance entered into on March 21, 2005 with the Company's lender, maturing September 19, 2005. On maturity, the Company will receive $20,262,000.

5. INVESTMENT

The Company has invested a total of $4,150,643 in 11.5 million common shares of Loon Energy Inc. ("Loon"), an oil and gas company which is listed on the TSX Venture Exchange. The Company acquired 7.9 million shares at a cost of $794,339 as part of the Plan of Arrangement and acquired 3.5 million shares at a cost of $3.4 million in a private placement which closed March 31, 2005. The investment is carried at cost. Fair value of the investment at March 31, 2005 was approximately $11.4 million. One officer and director of the Company is an officer and director of Loon. One officer of the Company is a director of Loon.

6. PROPERTY, PLANT AND EQUIPMENT

	March 31, 2005
Petroleum and natural gas properties	35,475,201
Accumulated depletion, depreciation	(1,139,870)
Net book value	34,335,331

As at March 31, 2005, the depletion calculation excluded unproved properties of $5.7 million.

The Company capitalized approximately $159,000 of geological and geophysical expenses associated with the exploration and development of capital assets during the period ended March 31, 2005.

The Company performed a ceiling test calculation at March 31, 2005 resulting in the undiscounted cash flows from proved reserves and the lower of cost and market of unproved properties exceeding the carrying value of oil and gas assets. The following table summarizes the future benchmark prices the Company used in the ceiling test:

	Crude Oil		Natural Gas
	West Texas (US$/bbl)	Edmonton (Cdn$/bbl)	AECO (Cdn$/mmbtu)
2005	54.00	65.00	7.70
2006	50.00	60.00	7.20
2007	47.50	57.25	6.95
2008	45.00	54.25	6.75
2009	42.00	50.50	6.50
2010	40.00	48.00	6.50
2011	40.00	48.00	6.50
2012	40.00	48.00	6.50
2013	40.50	48.75	6.65
2014	41.25	49.50	6.75
2015	41.75	50.25	6.85
Thereafter (2)	2.0%	2.0%	2.0%

(1) Future prices incorporated a $0.82 US/Cdn exchange rate for 2005 thereafter.

(2) Percentage change of 2.00 represents the change in future prices each year after 2015 to the end of the reserve life.

7. BANK DEBT

The Company has a $3 million demand revolving operating credit facility with a Canadian chartered bank and bears interest at the bank's prime lending rate plus three quarters of one per cent. The credit facility is secured by a $25 million fixed and floating charge debenture on the assets of the Company. None of the credit facility was drawn at March 31, 2005.

8. SHARE CAPITAL

a) Authorized:

– an unlimited number of common shares and preferred shares without nominal or par value.

b) Issued

Common shares were issued as follows:

	2005	
	Number	Amount
		($)
Balance, beginning of period	–	–
Issued with respect to Plan of Arrangement	17,660,371	12,782,895
Issued for cash		
Issue of common shares	15,500,000	46,325,000
Issuance of flow-through common shares	1,870,000	4,955,500
Less: Tax effect of flow-through shares	–	(1,750,000)
Share issue costs (net of tax effect of $955,000)	–	(1,769,846)
Balance, end of period	35,030,371	60,543,549

c) Stock Options:

The Company has a stock option plan where the Company may grant options to its service providers for up to 10% of its issued and outstanding common shares from time to time. Under this plan, the exercise price of each option equals the market price of the Company's stock on the date of grant. The maximum term of an option is 5 years.

Stock options vest one-third immediately and one-third on the first and second anniversary of the date of grant.

A summary of the status of the Company's stock option plan as of March 31, 2005 and changes during the period ended March 31, 2005 is presented below:

	Options	Weighted Average Exercise Price ($)
Granted	2,715,000	2.88
Outstanding at March 31, 2005	2,715,000	2.88

The following table summarizes information regarding stock options outstanding at March 31, 2005:

Exercise Price ($)	Number Outstanding	Number Exercisable	Weighted Average Remaining Contractual Life
2.25	2,065,000	688,333	4.7
4.55	120,000	40,000	5.0
4.95	530,000	176,667	4.9
	2,715,000	905,000	4.8

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the period ended March 31, 2005 was 27,398,838. In computing diluted earnings per share, 690,946 shares were added to the weighted average number of common shares outstanding during the period ended March 31, 2005 for the dilutive effect of stock options.

d) Stock-based Compensation:

The fair values of all common share options granted are estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair market value of options granted during the period ended March 31, 2005 and the assumptions used in their determination are as noted below.

	Period Ended March 31, 2005
Weighted average fair market value per option	1.1301
Risk-free interest rate (percent)	2.98%
Volatility (percent)	43
Expected life (years)	5

As described in note 1, the Company adopted the fair value based method of accounting for stock-based compensation for its stock option plan. Stock compensation is being recognized in earnings.

e) Shareholder Protection Rights Plan

A Shareholder Protection Rights Plan (the "Rights Plan") was approved as part of the Plan of Arrangement at the Special Shareholders Meeting October 28, 2004. The Rights Plan utilizes the mechanism of the Permitted Bid to ensure that a person seeking control of the Corporation (an "Acquiring Person") allows shareholders and the Board of Directors sufficient time to evaluate the bid. The purpose of the Permitted bid (a bid which provides that shares tendered to the bid will not be taken up prior to 60 days following the date of the bid) is to encourage a potential bidder to avoid the dilutive features of the Rights Plan by making a Permitted Bid or by negotiating with the Directors the terms of an offer which is fair to all shareholders.

If a Take-Over Bid does not qualify as a Permitted Bid the Rights Plan provides that shareholders other than the Acquiring Person may purchase shares at a reduced price, thereby diluting the value of the Acquiring Person's shares.

f) Contributed Surplus

The following table reconciles the Company's contributed surplus:

	Period Ended March 31, 2005
Balance, beginning of year	–
Stock based compensation expense	1,285,040
Balance, end of year	1,285,040

9. TAXES

Tax Expense

The combined provision for tax expense in the statement of loss and deficit reflect an effective tax rate which differs from the expected statutory tax rate. Differences were accounted for as follows:

	Period from November 2 to March 31, 2005
Loss before taxes	(1,982,718)
Statutory income tax rate	37.62%
Expected tax reduction	(745,898)
Add (deduct):	
Non-deductible stock-based compensation	483,400
Non-deductible crown charges	60,100
Resource allowance	(37,000)
Tax rate reduction	169,398
Future tax expense	(70,000)

Future Income Taxes

The future income tax asset at March 31, 2005 is comprised of the tax effect of temporary differences as follows:

	2005
Property, plant and equipment	288,000
Asset retirement obligations	131,000
Share issue costs	916,000
Future income tax asset	1,335,000

10. FINANCIAL INSTRUMENTS

a) Credit Risk

The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. To mitigate this risk, the Company sells substantially all of its production to two primary purchasers under normal industry sale and payment terms.

b) Foreign Currency Exchange Risk

The Company is exposed to foreign currency fluctuations as crude oil prices received are referenced in U.S. dollar denominated prices.

c) Fair Value of Financial Instruments

The Company's financial instruments recognized in the balance sheet consist of accounts receivable, accounts payable, bank indebtedness and obligations under capital leases. The fair value of these financial instruments approximates their carrying amounts due to their short terms to maturity or the indexed rate of interest on the bank indebtedness.

CORPORATE INFORMATION

BOARD OF DIRECTORS

Ian T. Brown
Calgary, Alberta

Earl T. Hickok, P. Eng. (1) (2)
Calgary, Alberta

Norman W. Holton
Calgary, Alberta

James E. Lawson, CA (1) (2)
Calgary, Alberta

John D. Morgan (1) (4)
Montreal, Québec

Murray D. Smith (3)
Washington, D.C.

(1) Audit & Reserves Committee
(2) Compensation & Corporate Governance Committee
(3) Nominee
(4) Retiring August 10, 2005

OFFICERS

Norman W. Holton, P. Geol.
Chairman

Ian T. Brown, P. Geol.
President & Chief Executive Officer

Gordon K. Case, CA
Vice President & Chief Financial Officer

Ed. A. Beaman, P. Eng.
Vice President, Production & Engineering

Wayne B. Jessee, P. Eng.
Vice President, Corporate Development

Brian W. Mainwaring
Secretary

AUDITORS

KPMG, LLP
1200, 205 – 5th Avenue S.W.
Calgary, Alberta
T2P 4B9

LEGAL COUNSEL

Gowling Lafleur Henderson LLP
1400, 700 – 2nd Street S.W.
Calgary, Alberta
T2P 4V5

THIRD PARTY ENGINEERING

Gilbert Laustsen Jung Associates Ltd.
4100, 400 – 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

BANKERS

National Bank of Canada
2700, 530 – 8th Avenue S.W.
Calgary, Alberta
T2P 3S8

TRANSFER AGENT & REGISTRAR

Computershare Trust Company of Canada
600, 530 – 8th Avenue S.W.
Calgary, Alberta
T2P 3S8

TUSK Energy Corporation
1900, 700 – 4th Avenue S.W.
Calgary, Alberta, T2P 3J4
Bus: (403) 264-8875
Fax: (403) 263-4247

E-mail: tusk@tusk-energy.com
Website: www.tusk-energy.com

ABBREVIATIONS

1P: Proved Reserves pursuant to NI 51-101

2P: Proved plus Risked Probable Reserves pursuant to NI 51-101

ARTC: Alberta Royalty Tax Credit

APO: after payout

BPO: before payout

BTAX: before income tax

bopd: barrels of oil per day

bpd: barrels per day

boe or BOE: barrels of oil equivalent

boepd: barrels of oil equivalent per day

DCF: discounted cash flow

GRP: gas reference price

Mbbls: thousands of barrels

Mcf: thousand cubic feet

Mcfd: thousand cubic feet per day

MMcf: million cubic feet

MMcfd: million cubic feet per day

MRL Maximum Rate Limitation

NAV: net asset value

NI 51-101: National Instrument 51-101

NGL: natural gas liquids

RLI: reserve life index

SIGW: Shut-in gas well

WTI: West Texas Intermediate

CONVERSIONS

1 barrel of oil = 0.15891 cubic metres

1 Mcf of gas = 28.17399 cubic metres

1 barrel of oil equivalent (BOE) = 6 Mcf gas

produced by **ion** communications

TUSK Energy Corporation
Suite 1900
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